RHODE ISLAND ENERGY

2024 Electric Peak (MW) Forecast

15-Year Long-Term

2025 to 2039

December 2024

Energy Planning, Analysis, & Forecasting

Rhode Island Energy™

a PPL company

GENERAL NOTES

<u>General Notes</u>:

- Hourly load data through August 2024; projections from 2024 winter forward.
- Economic data is from Moody's vintage Summer 2024.
- Energy Efficiency, electric heating, solar, energy storage, and demand response is internal data vintage Summer 2024.
- Electric Vehicle, for medium- and heavy- duty electric vehicles and E-buses, data is S&P Global (formerly POLK) data vintage Summer 2024.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (Jan. 2003 to Jun. 2024), internal unreconciled **<u>preliminary</u>** data (Jul. 2024 to Sep. 2024).
- Peak load data is metered zonal load, but without ISO bulk system losses.

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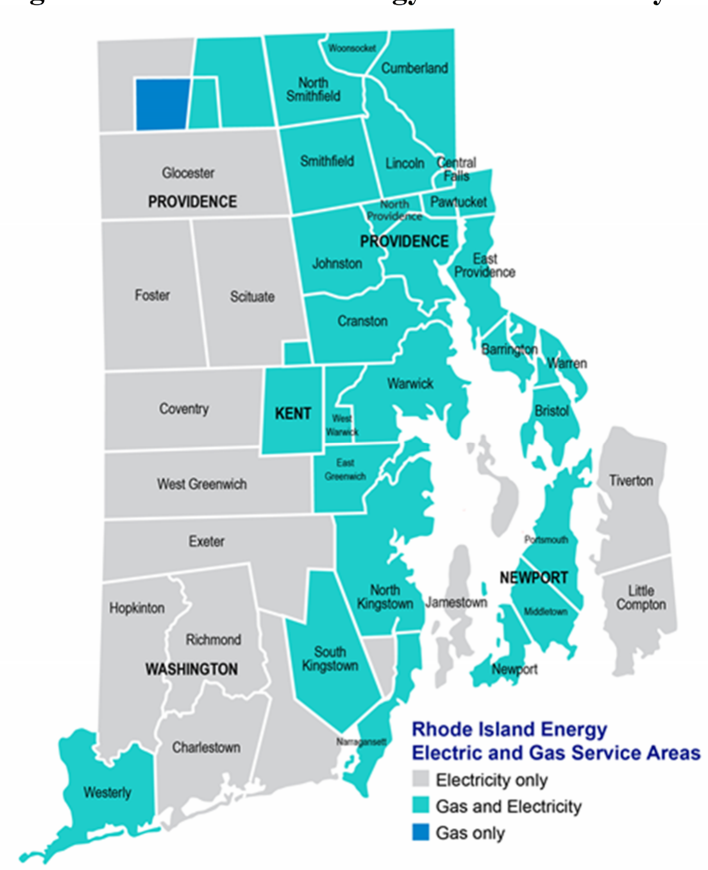
CONTENTS

Summary

Rhode Island Energy

Rhode Island Energy ("RIE" or the "Company"), formerly known as Narragansett Electric Company, serves approximately 486,000 electricity customers in Rhode Island. Figure 1 shows the Company's service territory.

Figure 1: Rhode Island Energy Service Territory



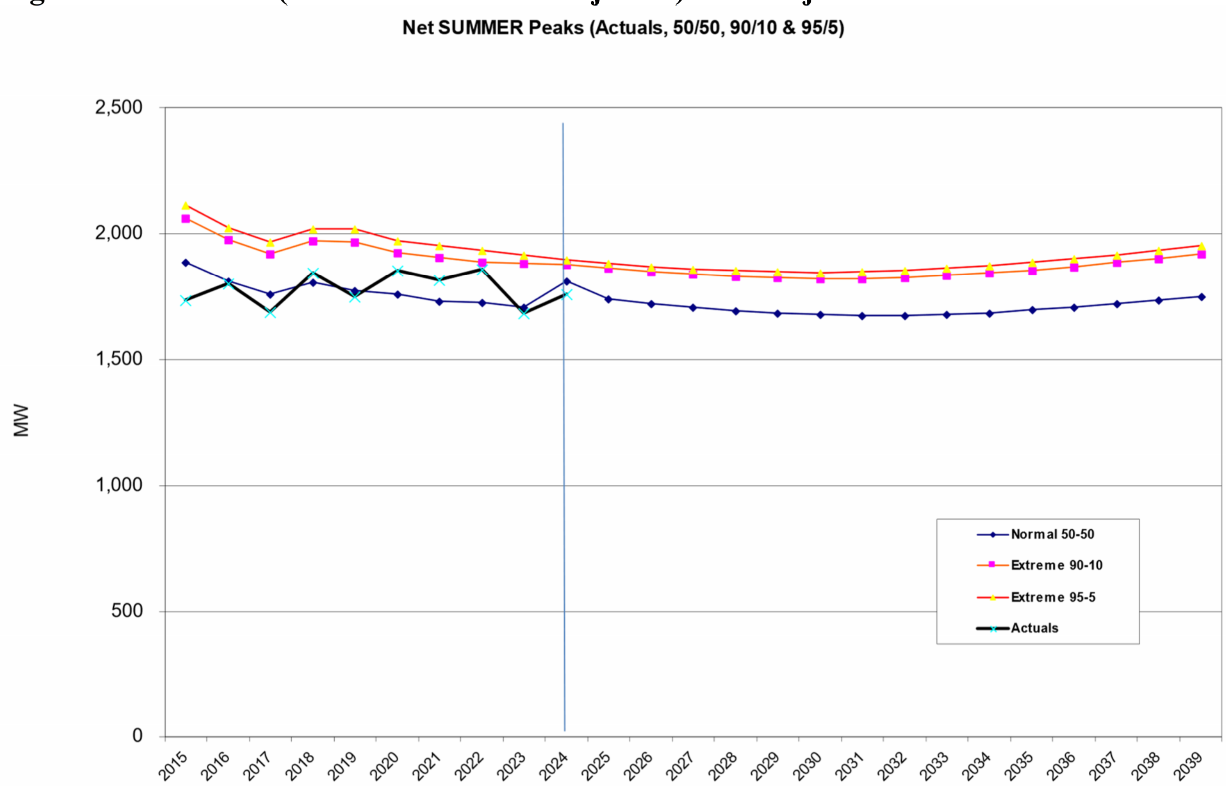
The goal of the Company's planning process is to provide safe, reliable service at the lowest reasonable cost to customers while complying with all laws and regulations. Electricity is vital to Rhode Island's economy and public safety, and customers expect electricity to be available at all times and in all weather conditions. An understanding of the way customers use electricity is critical for planning a distribution system that can reliably serve customers in every moment. Forecasting peak electric load is necessary for the Company's planning processes so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.

The Company's peak demand in 2024 was 1,759 MW on Friday, August 2 at hour-ending 16. This 2024 peak was 11% below the company's all-time peak of 1,985 MW reached on Wednesday, August 2, 2006.

This summer's temperature for the Company peak was below average. The temperature at peak fell in the 5th percentile of peak weather over the last 20 years and was the lowest in the last 20 years. This means that 95% of summer peaks are expected to be warmer. As a result, this year's peak is approximately 54 MW below the peak that would have experienced under normal peak weather conditions. Thus, on an adjusted "normal" basis this year's peak was estimated to be 1,813 MW, an increase of 6.2% compared to last year's adjusted peak.

Compared to 2024 actuals, RIE expects relatively flat peak load in the 15-year forecast period characterized by slightly decreasing peak load in the next seven years followed by slight growth in the late years of the forecast horizon when slowing energy efficiency improvements are outpaced by additional load from increasing penetration of transportation electrification. Summer peak remains to be the annual peak for the Company throughout the forecast horizon. Figure 2 shows this forecast graphically.

Figure 2: Historical (Actual & Weather-Adjusted) and Projected Summer Peaks



Due to increasing distributed solar photovoltaics ("PV") and electric vehicles ("EV"), the hour of the peak slightly moves over the forecast period from late afternoon/early evening to later in the evening. As this occurs, the impact of distributed PV on peak demand is less pronounced.

Forecast Methodology

To develop a peak demand forecast, the Company first forecasts reconstituted, or "gross," peak demands, which exclude the estimated impacts of energy efficiency, distributed PV, distributed energy storage, demand response, electric vehicles, and electric heat pumps. The impacts of these "key forecast uncertainties" are then forecasted individually and added back to the gross peak demand forecast to arrive at the final, or "net," forecast.[1]

Energy efficiency, distributed PV, distributed energy storage, and demand response reduce peak demands, while electric vehicle charging can increase peak demands. Electric heat pumps ("EH") could increase or decrease peak demands depending on the season and technology being replaced. For purposes of reconstituting history to account for electric heat pumps, the Company assumes that electric heat pumps increase winter peaks and decrease summer peaks, albeit marginally in both seasons.

The results of this forecast are used as inputs into various system planning studies. The forecast is presented for three peak weather scenarios.[2] The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes while distribution planning uses the 95/5. The 50/50, or normal weather scenario, is used for capacity market, strategic scenarios, incentive mechanisms, and other relevant work.

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[1] These key forecast uncertainties have historically been referred to in this report as distributed energy resources or "DER." For purposes of this year's report, they will be referred to as "key uncertainties."

[2] For purposes of this report, the term "weather" refers to temperature-driven metrics such as the daily high temperature or heat index. The term weather is not referring to storms, wind, rain, flooding, etc. which can also impact the distribution system.

Weather Assumptions

Weather data for this analysis is collected from the Providence (or T.F. Green) weather station and used to weather-normalize peak demands.

The weather variables used in modeling include daily maximum temperature, a temperature-humidity index (THI)[3], and cooling degree days for the summer peak days, and daily minimum temperature, the THI, and heating degree days for the winter peak days. THI uses a weighted three-day index (WTHI)[4] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[5].

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is the level that 90% of peak weather falls below.
- Extreme 95/5 weather is the level that 95% of peak weather falls below.

These normal and extremes are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Figure 3 shows the historical, normal, and extreme weather values for WTHI for the Company.

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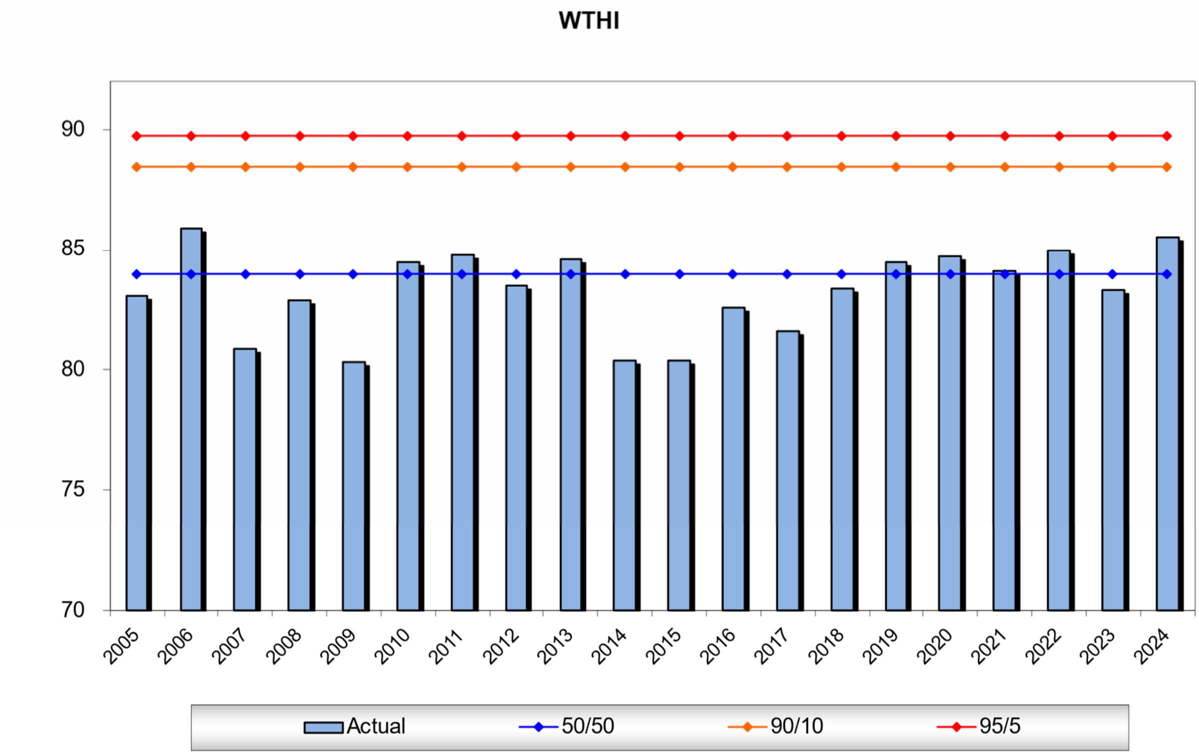
[3] THI is a calculated value also referred to as "Heat Index" provided by Accuweather. The maximum value for each day was used in the WTHI formula prior to 2023; the average of the day was used in 2023 and 2024.
[4] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[5] Normal distribution is assumed to derive the extreme weather scenarios. This probabilistic approach employs Z-scores and standard deviations to calculate the extreme weather scenarios.

Figure 3: Actual, Normal, and Extreme WTHI



Key Forecast Uncertainties

In Rhode Island, there are a number of policies, programs, and technologies that could impact customer loads. These include, but are not limited to, energy efficiency ("EE"), distributed PV, EV, demand response ("DR"), distributed energy storage ("ES"), and EH. These collectively are termed "key uncertainties" because their impact on future peak demands is uncertain.

The Company developed base, low, and high case forecasts for each of the key uncertainties except ES and DR; only a base case forecast was developed for these items. The highest and lowest case load forecasts were developed using the most extreme cases of each uncertainty that would produce the highest and lowest load. The discussion below assumes the base case for each uncertainty.

Figure 4 shows expected net and gross load, and Figure 5 shows the impacts for the uncertainties each year. On average, gross load is projected to grow by 0.02% per year over the next five years. Net load is projected to decrease by 1.5% per year over the next five years. Over the fifteen-year forecast period, the net peak is expected to decrease by 0.6% per year due primarily to EE and the increasing penetration of distributed PV more than offsetting growth in EV.

Figure 4: Annual Gross and Net Peaks

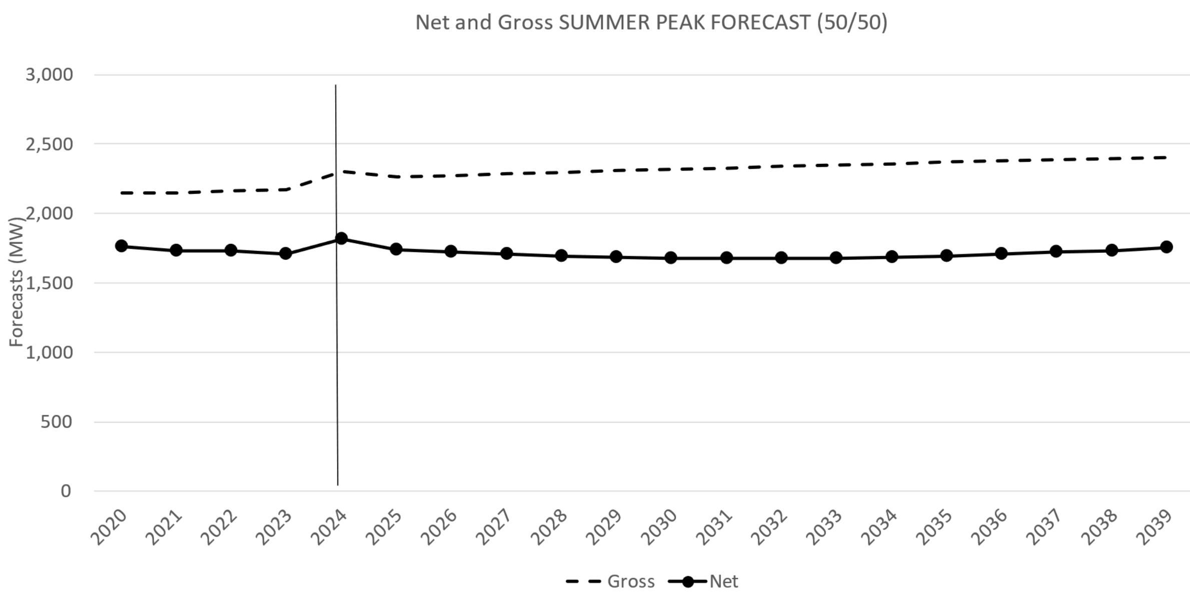
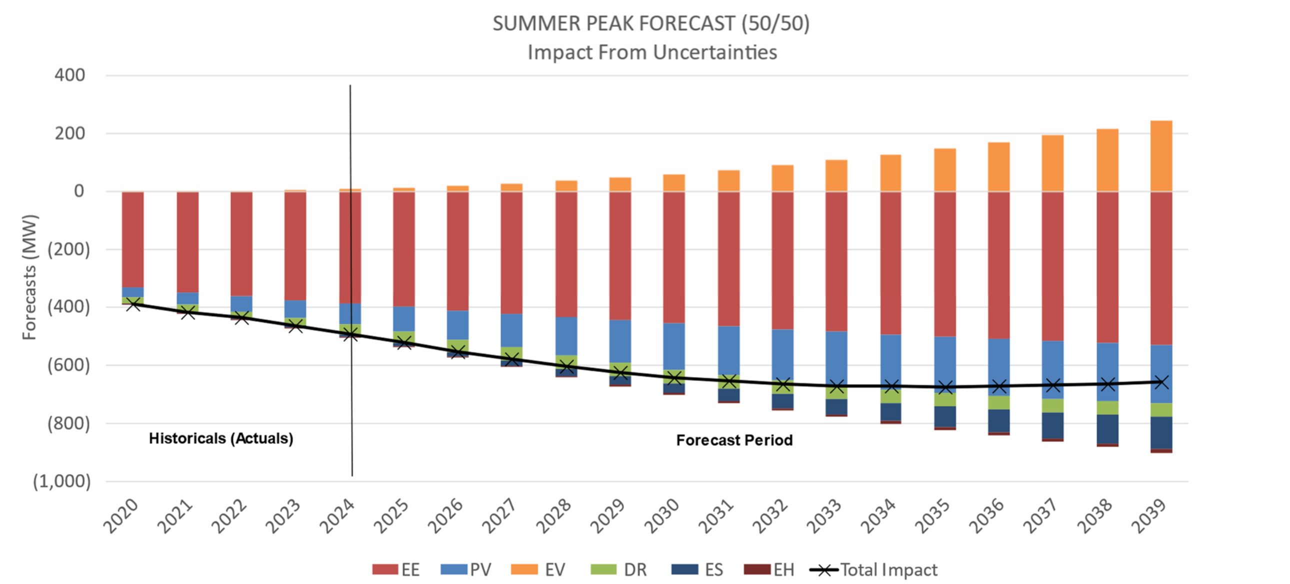


Figure 5: Impact of Key Uncertainties on Peak



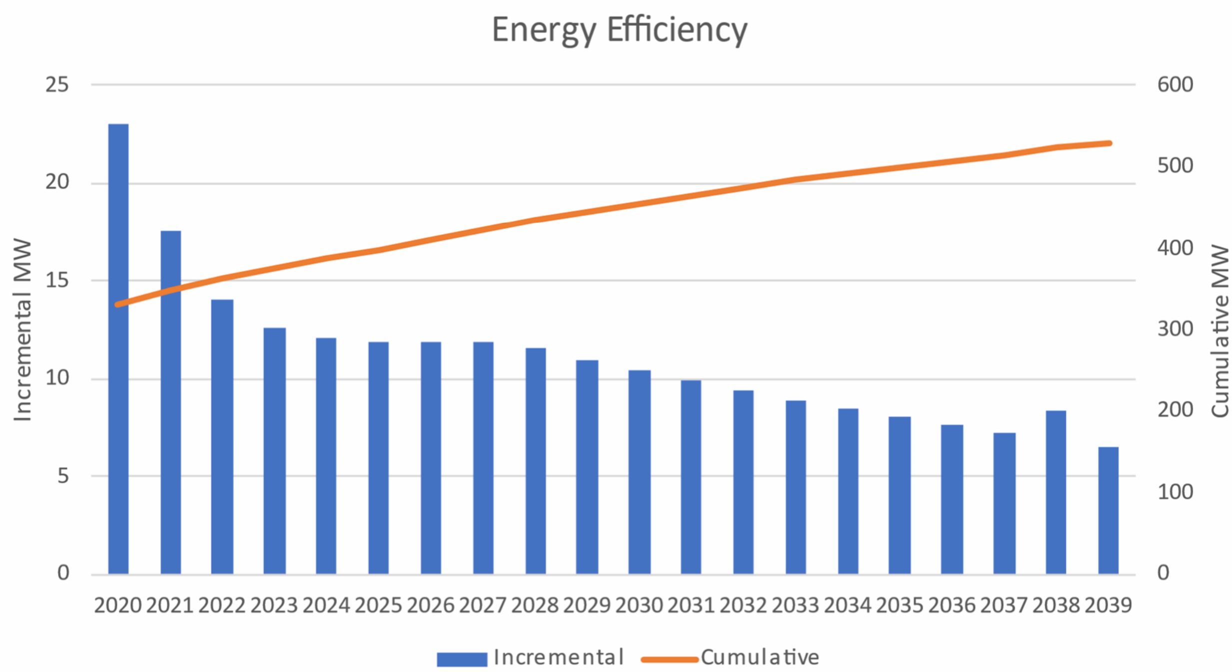
Each of the key uncertainties is discussed in the sections below.

<u>Company-Sponsored Energy Efficiency Programs</u>

Rhode Island Energy has sponsored EE programs for many years and will continue to do so for the foreseeable future. Estimated EE impacts for the historical period and the initial 3 years of the forecast period are based on the Company's three-year EE plan. According to the Energy Information Administration, incremental improvements in end-use efficiencies will diminish over time as end-use efficiencies approach their technical potential, and the Company's EE forecast is consistent with these projections.

Figure 6 below shows the base case energy efficiency program impacts to peak demands. As of 2024, these EE programs have reduced load by an estimated 387 MW, or 16.8% compared to the 2024 gross weather-normalized peak. By 2039, this reduction grows to 529 MW or 22% of what load would have been had these programs not been implemented. Over the fifteen-year planning horizon, the impact of EE reductions lower annual peak growth from 0.3% to -0.1% per year. Figure 6 presents the annual incremental (left) and cumulative (right) estimated EE summer peak MW reductions.

Figure 6: Energy Efficiency Summer MWs by Year



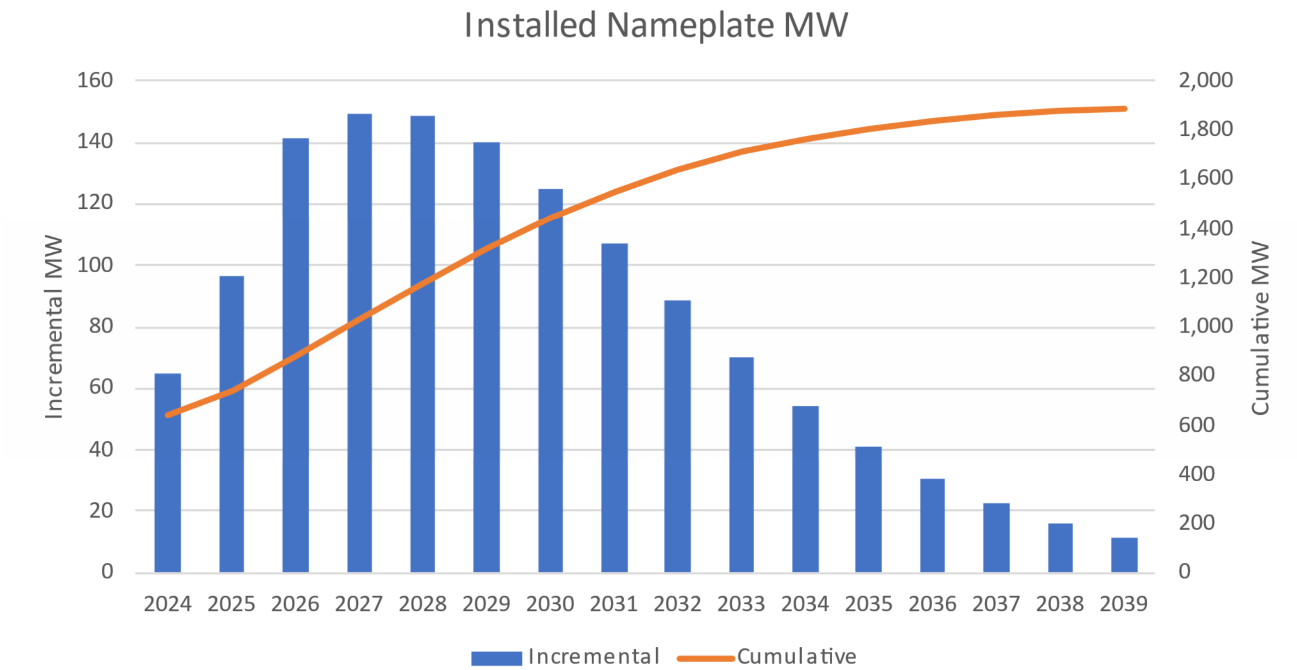
Distributed Solar Photovoltaic[6]

Actual distributed solar installations and capacity are tracked by the Company and used to estimate the historical contributions of distributed PV to peak demand. The projection for the future is based on an estimate of installations for units already in the application queue for the current year, then a continuation of those levels until year 2027, and then a slowly declining number of new annual installations to account for saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Figure 7 shows the projected connected PV installations. As of 2024, it is estimated about 645 MW will have been connected, growing to 1,888 MW by the end of the planning period.

[6] This discussion is limited to PV which is expected to reduce loads and would not include those PV installations considered to be supply by the ISO. This can include both "behind-the-meter" and in "front-of-the-meter" (e.g. community solar which is allocated back to customers).

Figure 7: Distributed Solar-PV Connected Nameplate (AC) MW by Year



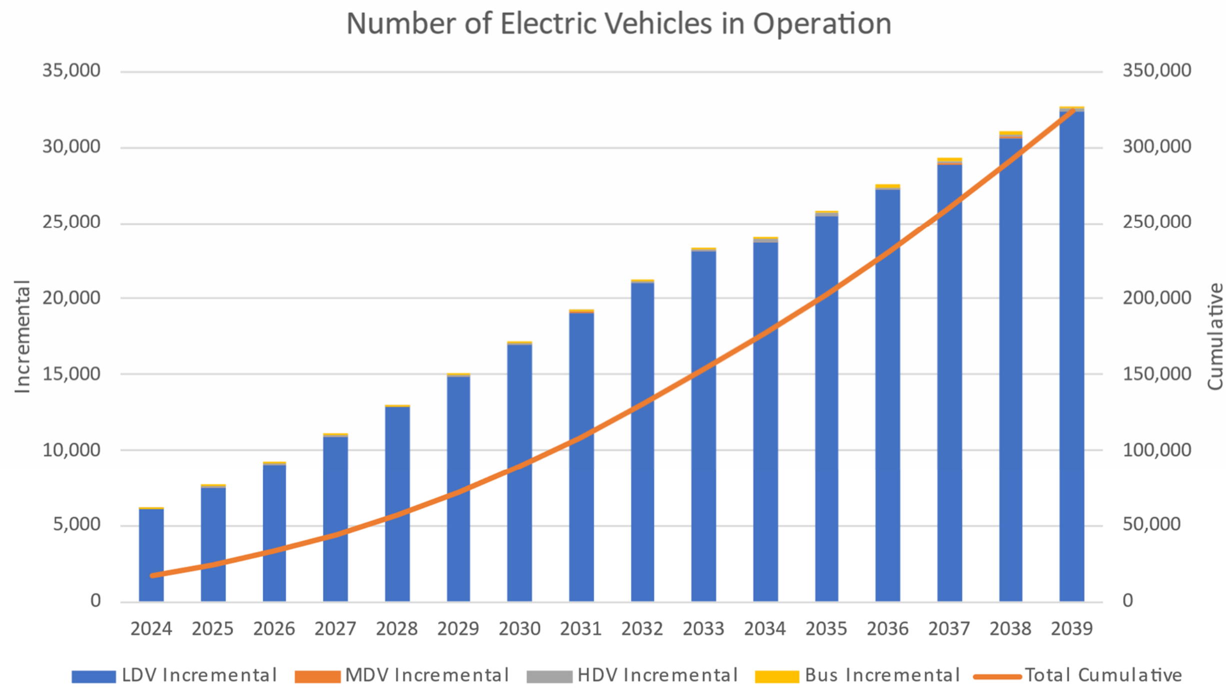
While installed distributed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less solar irradiance.

Electric Vehicles

EVs will increase peak load over time barring the introduction of rates or programs to reduce the impact. Forecasted EVs include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). While light-duty EVs ("LDV") are assumed to by far be the most widely adopted and thus the most impactful on electric load, the Company also includes medium-duty EVs ("MDV"), heavy-duty EVs ("HDV"), and electric buses in the electric load forecast.

Figure 8 shows the future estimated number of EVs in the Company's Rhode Island service territory. As of the end of 2024, it is estimated that about 16,772 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the service territory, growing to almost 325,000 by the end of the fifteen-year planning horizon.

Figure 8: Number of Incremental and Cumulative EVs



It is estimated that these vehicles may have increased cumulative summer peak loads by about 9.4MW as of 2024. This grows to 244 MW of cumulative peak load increase by 2039.

Demand Response

DR programs actively target reductions to peak demand during hours of high expected demand or hours having reliability problems. These resources must be dispatched, unlike the more passive energy efficiency programs that provide savings throughout the year. The DR programs enable utilities and the Independent System Operator ("ISO") to act in response to a system reliability concern or pricing signals. During these events, a customer can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

In general, there are two categories of Demand Response programs in Rhode Island – ISO programs and Company retail-level programs.

The ISO programs, referred here as "wholesale DR," have been active for several years and were activated multiple times over that period. The Company's policy has been to add-back reductions from these dispatches to its reported system peak numbers. Because the Company cannot dispatch the ISO resources, there is no guarantee that these ISO DR events would be at the times of Company peaks. Therefore, the Company must plan assuming they are not called.

The Company recently began to run its own DR program, referred here as "retail DR," over the last few years. In contrast to the wholesale level DR programs implemented by the ISO, the retail programs are activated by the Company.

In 2024, estimated impact of the retail DR program was about 35 MW and is expected to grow to about 46 MW by year 2029. No additional incremental DR MW is expected beyond that point because it is assumed that the program's market potential is at its maximum by then, but the cumulated MW is expected to be carried through the rest of the forecast horizon.

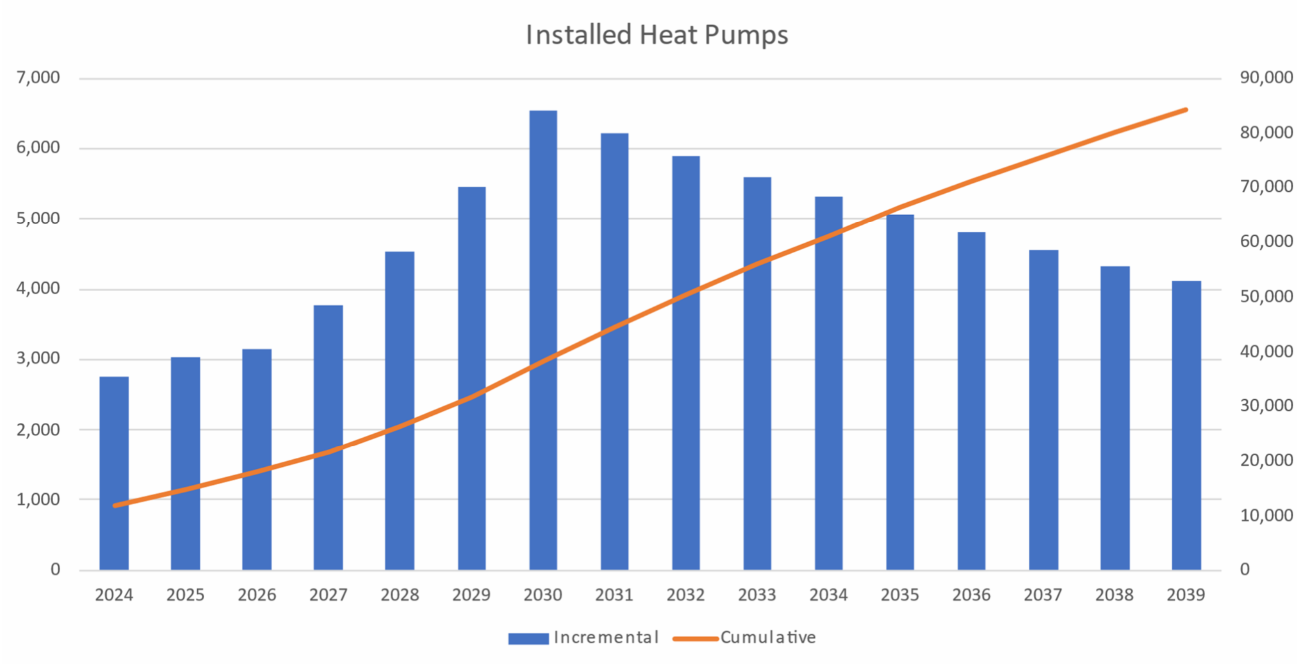
Distributed Energy Storage

Rhode Island Senate Bill 2499, known as the "Energy Storage Systems Act," recently established targets for energy storage capacity of 90 MW by December 31, 2026, 195 MW by December 31, 2028, and 600 MW by December 31, 2033. These targets were not directly incorporated into the forecast as the mechanisms by which these targets will be achieved have not yet been defined. While the act does not include provisions for specific funding, some financial incentives are currently available. CommerceRI's Renewable Energy Fund (REF), the federal Inflation Reduction Act, and the Company's ConnectedSolutions Battery Program all include provisions for battery storage. With these provisions, about 2.32 MW of storage was installed through 2023. By 2038, it is estimated that storage may help shave the summer peak load by about 72 MW. It is also noted that there is a small amount of storage being captured in the Company's Demand Response program in Rhode Island through the ConnectedSolutions program. By May 1, 2025, the Public Utilities Commission will adopt a framework for an energy storage system interconnection tariff that will more clearly outline the monetary incentive to adopt these systems.

Electric Heat Pumps

The base case for electric heat pump adoptions is based on the Company's pro rata share of the ISO-NE heat electrification forecast, which is a projection for residential heat pumps installations in the state. Commercial heat pumps are not currently incentivized. Incremental adoption continues to grow until 2030, at which point incremental growth begins slows down. Figure 9 shows the annual number of electric heat pumps assumed for the forecast.

Figure 9: Number of Electric Heat Pumps



All prior discussion on load and uncertainties above is limited to the <u>base</u> case. Additional high and low scenarios are provided later in this section (see "Key Forecast Uncertainties Scenarios") and in the Appendices.

Peak Day 24 Hour Load Curves

While the single hour peak values discussed above are of major importance, the Company forecasts demand and the impact of key uncertainties for all hours of the peak day in each year. This approach is useful to show the changing hours of the peaks as the level of different uncertainties change over time. For example, as more and more PV is added to the system, the summer peak hour will shift away from afternoon hours where solar irradiance is highest to evening hours as the solar reductions taper off. As more electric vehicles are adopted, evening and nighttime loads could go up depending upon measures that could be taken to incentivize customers to charge at different hours of the day.

Figure 10 shows the hourly profile of the peak summer day for selected years over the planning horizon for the base case uncertainties.

Figure 10: Net and Gross Peak Summer Day Hourly Load

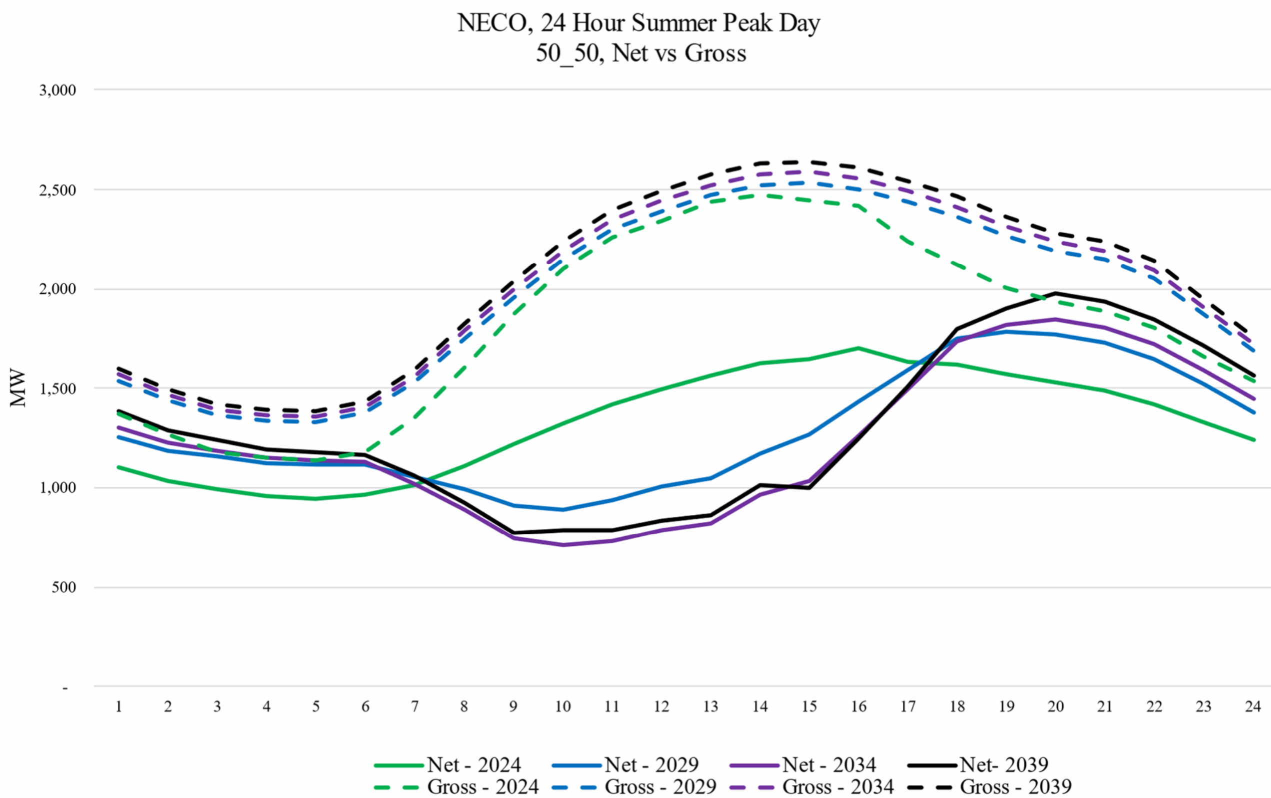


Figure 10 clearly shows how the expected uncertainties not only lower the loads, but also shift the hour of the peaks.

Figure 11 shows the hourly profile of the peak winter day for selected years over the planning horizon with the base case uncertainties.

Figure 11: Net and Gross Peak Winter Day Hourly Load

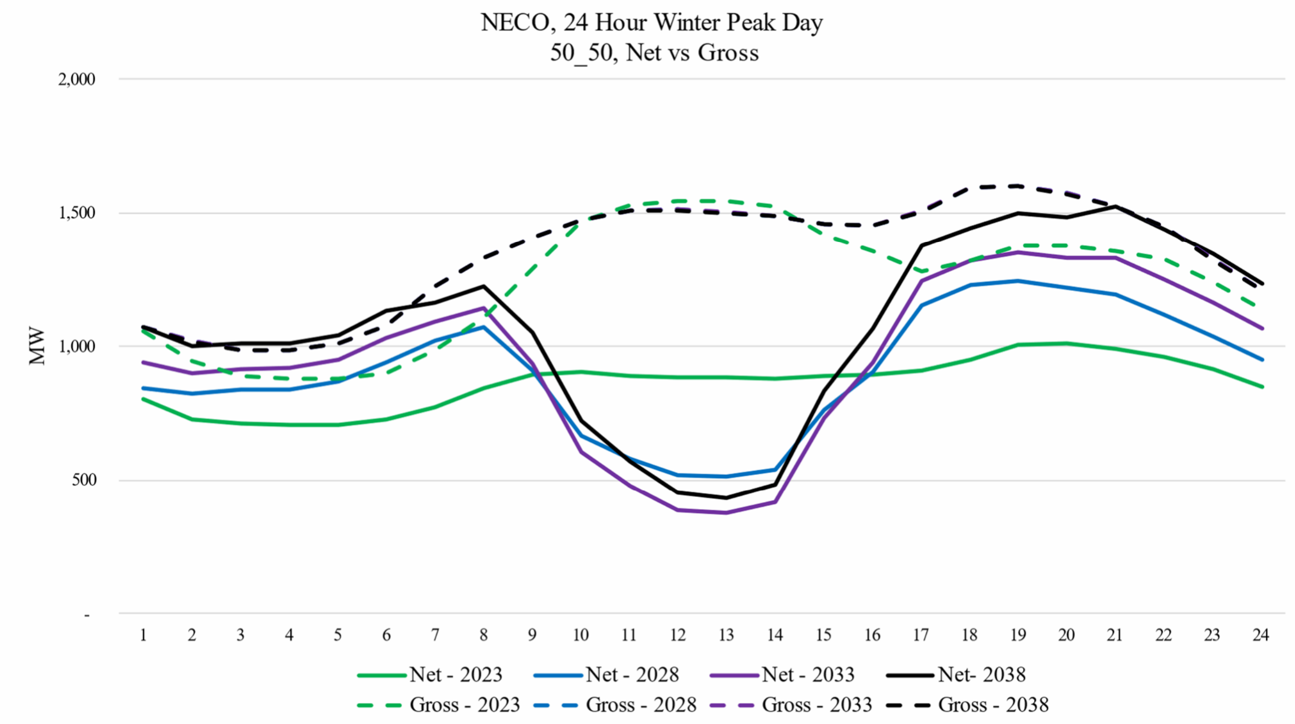


Figure 11 shows the dual peaks associated with winter days as well as the potential for very low load hours during the daytime due to solar and the rapid ramp needed as the sun sets. An increasing penetration of electric heat pumps and electric vehicles could increase morning and evening usage in later years of the forecast period. The figures above show the gross and net load profiles for the base case uncertainties.

Appendix C contains additional hourly load shapes for other day types including summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is reduced commercial and industrial load.

Key Forecast Uncertainties Scenarios

Thus far, this report has shown results for the peak forecast with the base case forecasts for key uncertainties. The Company also developed high and low case scenarios for the following key uncertainties: EE, PV, EV, and EH. Looking at a range of scenarios can provide planners with additional information on what loads might be under high and low scenarios.

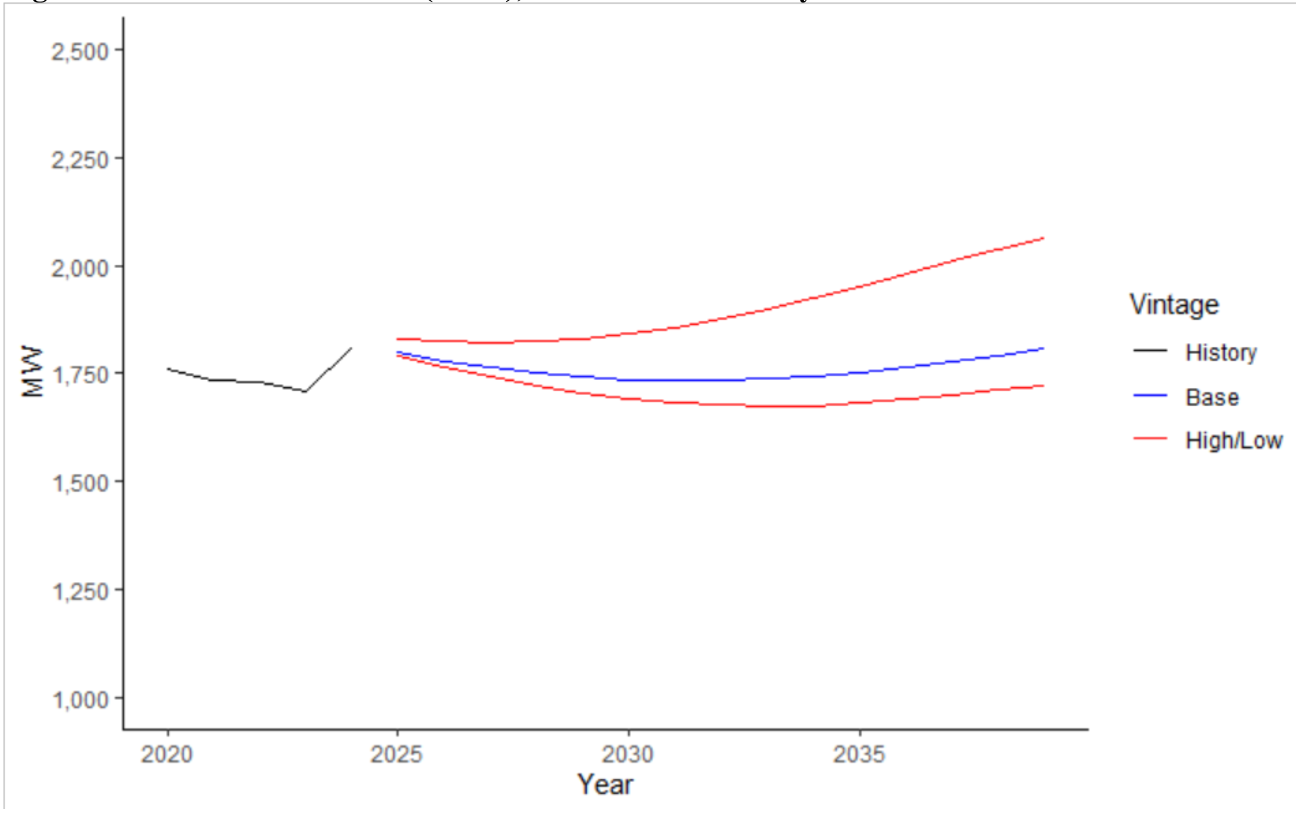
Each of the various combinations of uncertainty scenarios – base, high, and low – were modeled.[7] While this creates many combinations, the Company chose to focus primarily on the base, high, and low load cases created by the uncertainty combinations.

Figure 12 shows the base case (which the Company deems to be the most reasonable scenario) as a continuation of the historical normalized data and the maximum and minimum cases in red lines which provide the highest and lowest load bounds for planning purposes. The base is the scenario with base cases from all uncertainties. The maximum load scenario is the scenario where load reducing key uncertainties such as energy efficiency and PV are minimized, while load increasing key uncertainties such as EVs are maximized. The minimum load scenario is the scenario where load reducing key uncertainties are maximized and load increasing key uncertainties are minimized.

The peak load five years from now in year 2029 ranges from 1,704 MW to 1,830 MW - a 126 MW spread, with the base case at 1,741 MW. The uncertainty increases over time, so that fifteen years from now in year 2039 the range expands to 1,723 MW to 2,062 MW, or a 339 MW spread, with the base case at 1,809 MW. It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are unlikely.

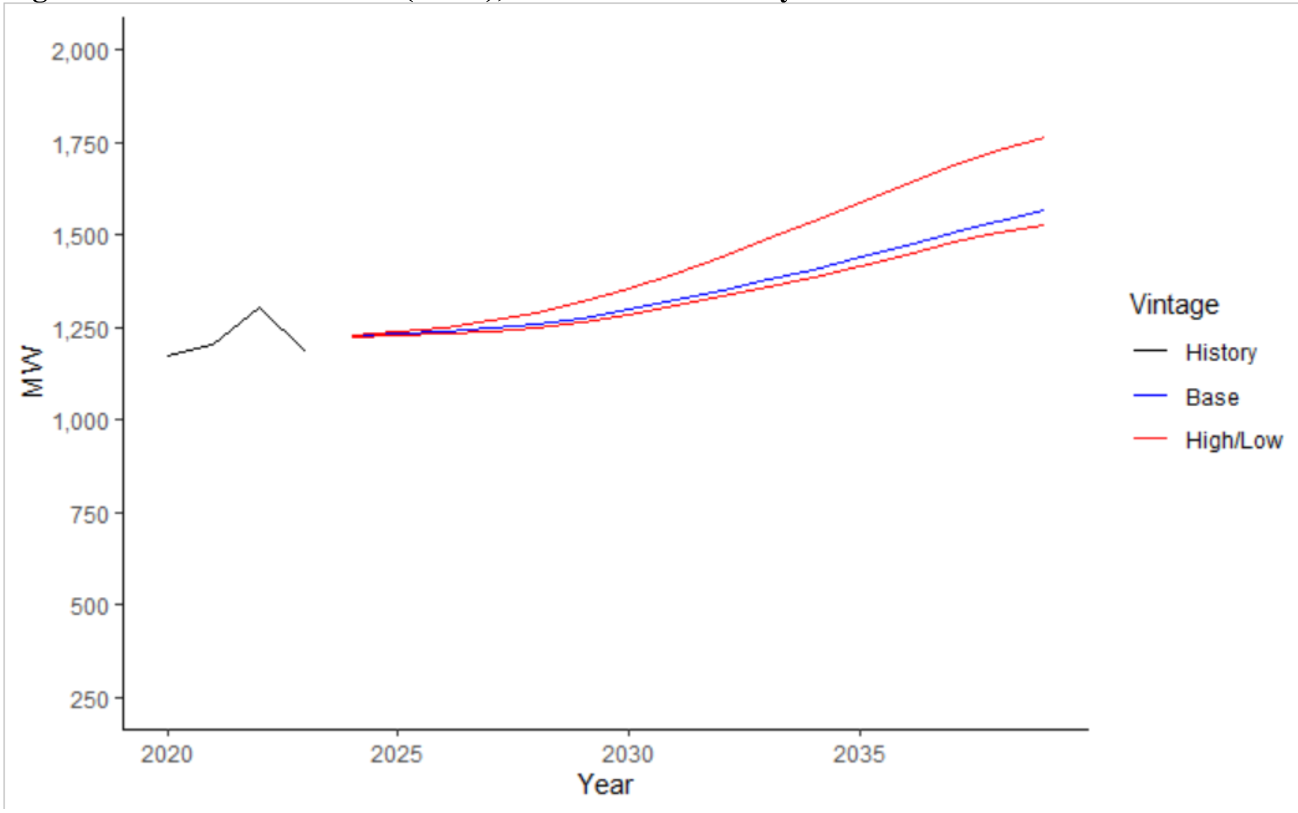
[7] The base case uncertainty projections included in this forecast are based on current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. The higher and lower scenarios are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive. These can include, among other things, additional electrification of the transportation and heating sectors and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

Figure 12: Net Summer Peaks (50/50), Selected Uncertainty Scenarios



Although summer peaks remain to be the annual peak throughout the forecast horizon, winter peaks attract increasing interest with the potential for electric space heating growth in the future. Figure 13 shows the winter peak load of selected uncertainty scenarios through the end of the forecast horizon in the same format as Figure 12. Please note, because the winter peak hour is expected to be hour-ending 19 or later, solar irradiance is not expected to be available for these projected peak hours and thus there is no PV saving expected for the net peak hour in winter.

Figure 13: Net Winter Peaks (50/50), Selected Uncertainty Scenarios



While Figure 12 and Figure 13 above show what the longer term annual single summer peaks and winter peaks look like, Figure 14 and Figure 15 show peak day hourly profiles for selected years.

Figure 14: 50/50 Case, Net Summer Peak with Range of Uncertainty Scenarios, 2029

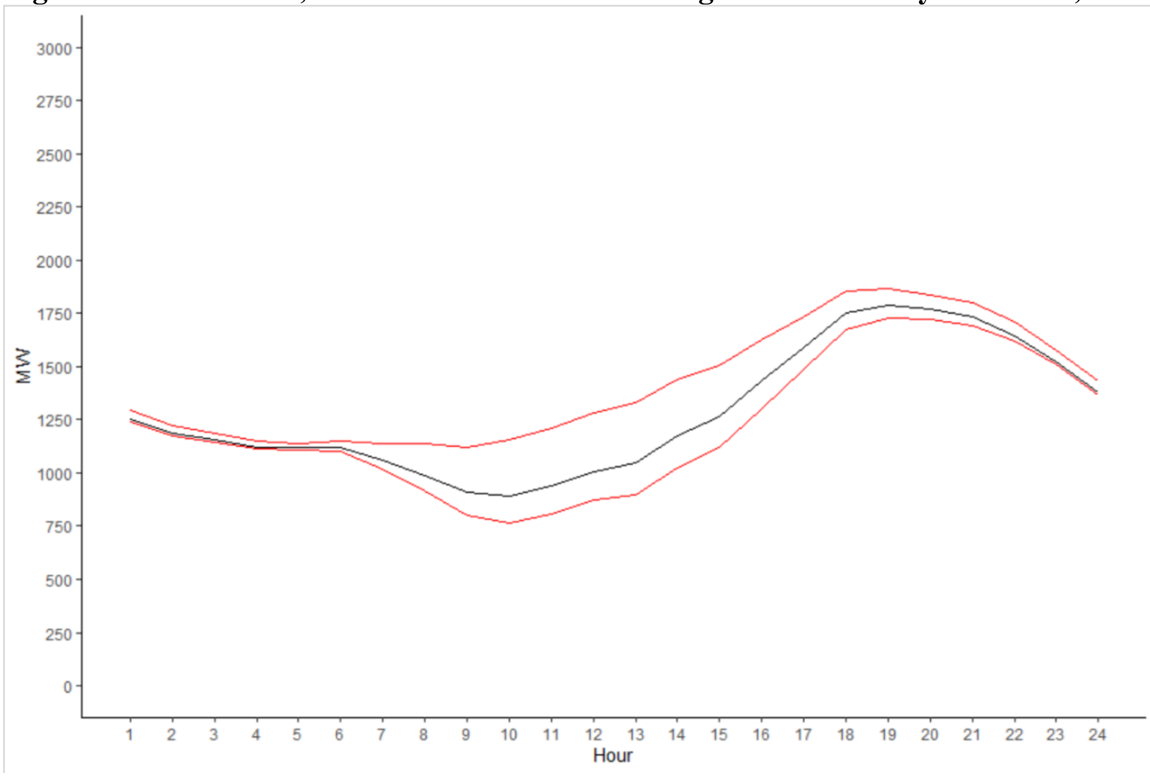


Figure 15: 50/50 Case, Net Summer Peak, with Range of Uncertainty Scenarios, 2039

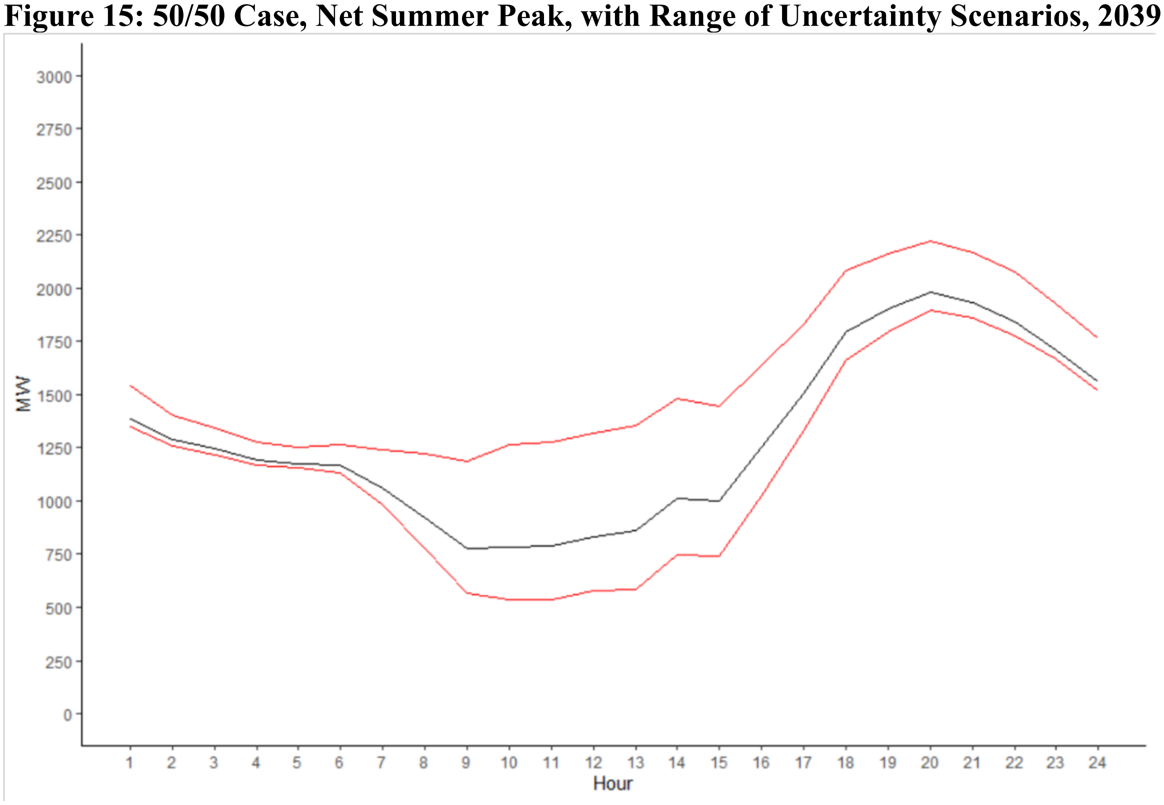


Figure 16: 50/50 Case, Net Winter Peak, with Range of Uncertainty Scenarios, 2028

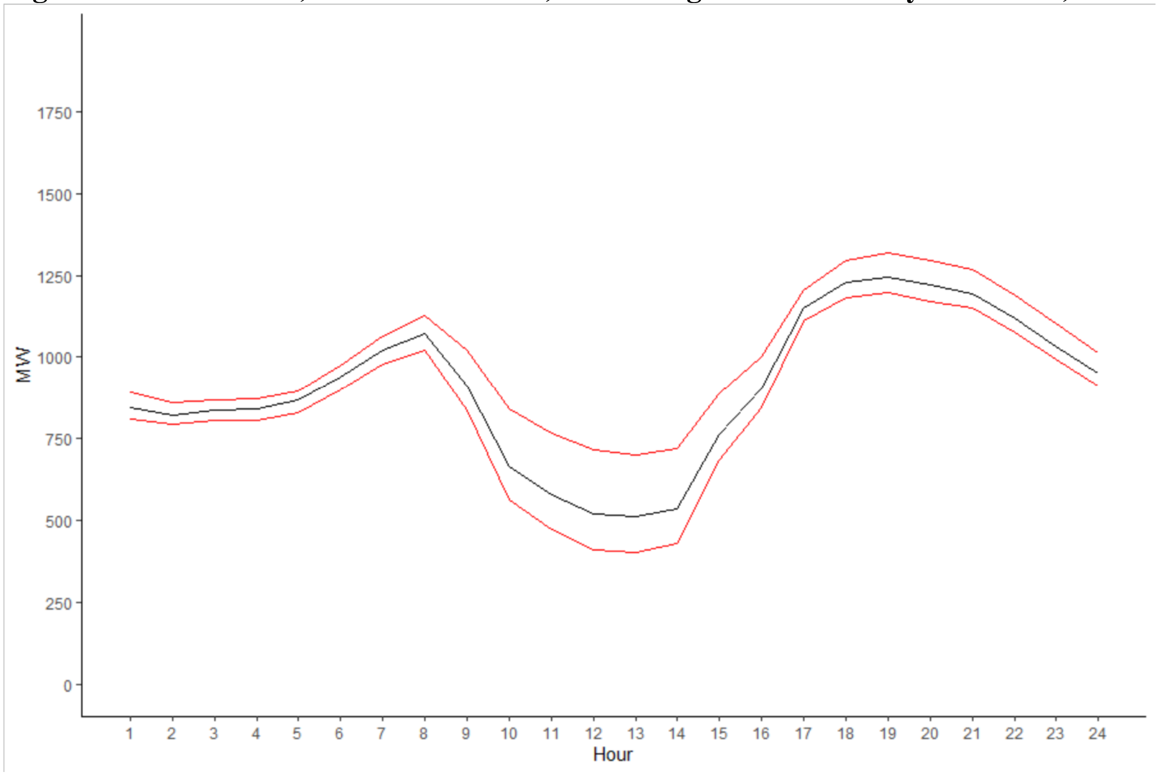
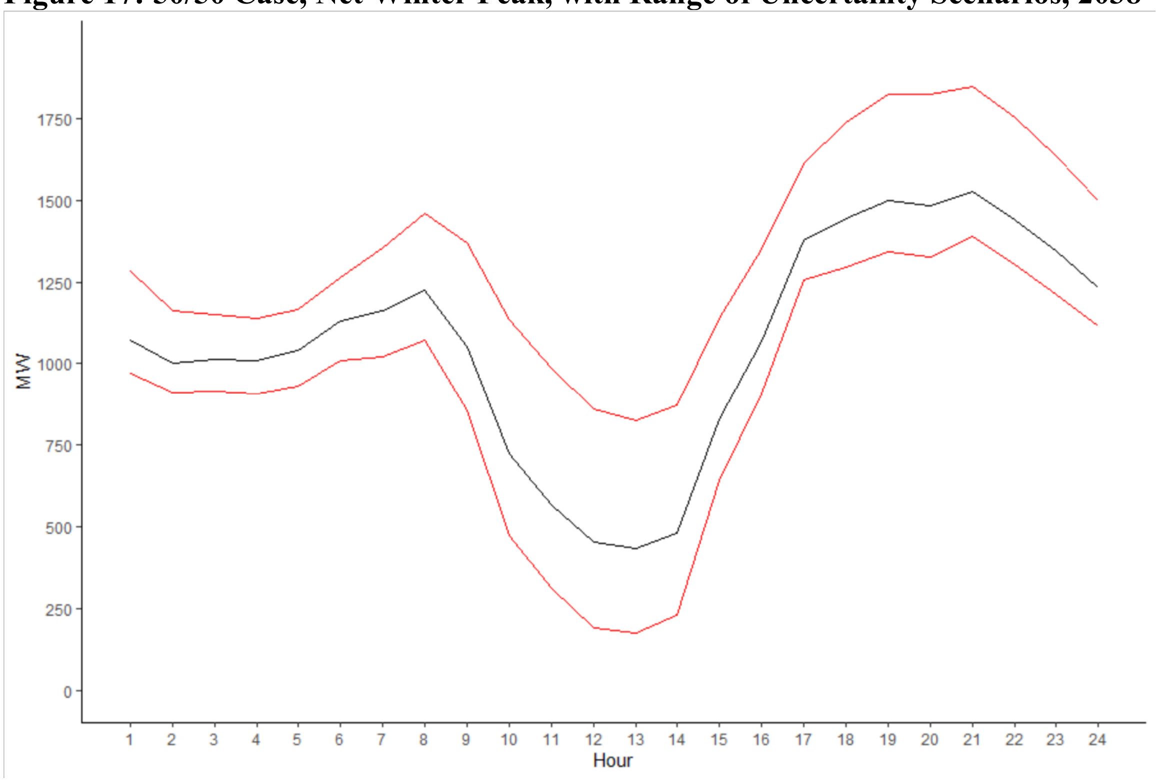


Figure 17: 50/50 Case, Net Winter Peak, with Range of Uncertainty Scenarios, 2038



What becomes apparent is that the range of possible outcomes in the early years (Figure 14 and Figure 16) is more narrow, but increases fifteen years out (Figure 15 and Figure 17). Note that the midday hours have a wider range of possible loads than other times of the day primarily because of the distributed solar resource.

Appendices D and E describe the process for determining these scenarios and what the input cases look like.

Extreme Weather Analysis

Seasonal peaks are highly dependent upon extreme weather, and they typically occur on some of the hottest days of the summer and coldest days of the winter. While the trend in average annual temperatures has been slightly increasing in recent decades, the trend in annual high and low temperatures has been mostly flat.

Figure 18 and Figure 19 show annual high and low temperatures since the early 1970s. Based on the 10- and 20-year rolling averages, the trend in annual winter low temperatures has been flat to slightly declining (getting colder) since 2010. The figures also show the wider range of winter low temperatures relative to summer high temperatures. This means that the winter peak can deviate from the mean far more than the summer peak. The figures also show that the 20-year rolling average is more stable and less impacted by one year being added to or rolling off the rolling average than the 10-year rolling average, particularly for the more volatile low temps.

Because the weather data does not support a warming trend in seasonal extreme temperatures, the Company's peak forecast does not contemplate warming extreme temperatures in the future.

Figure 18: Historical Annual High Temperatures (°F)

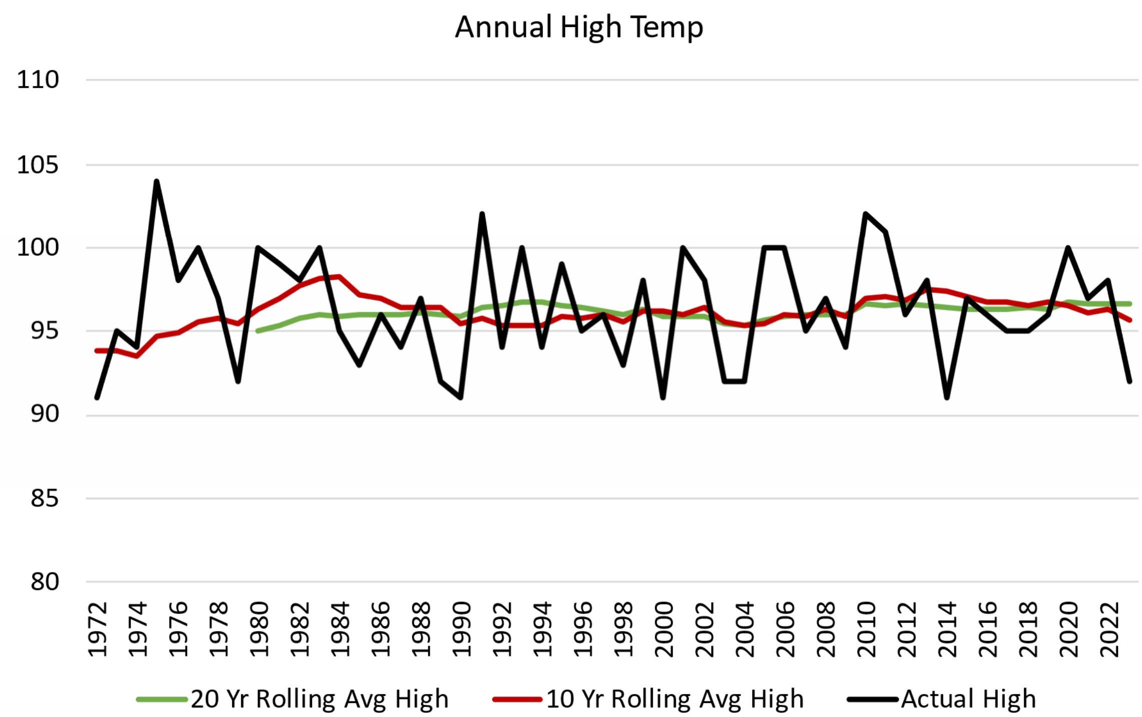
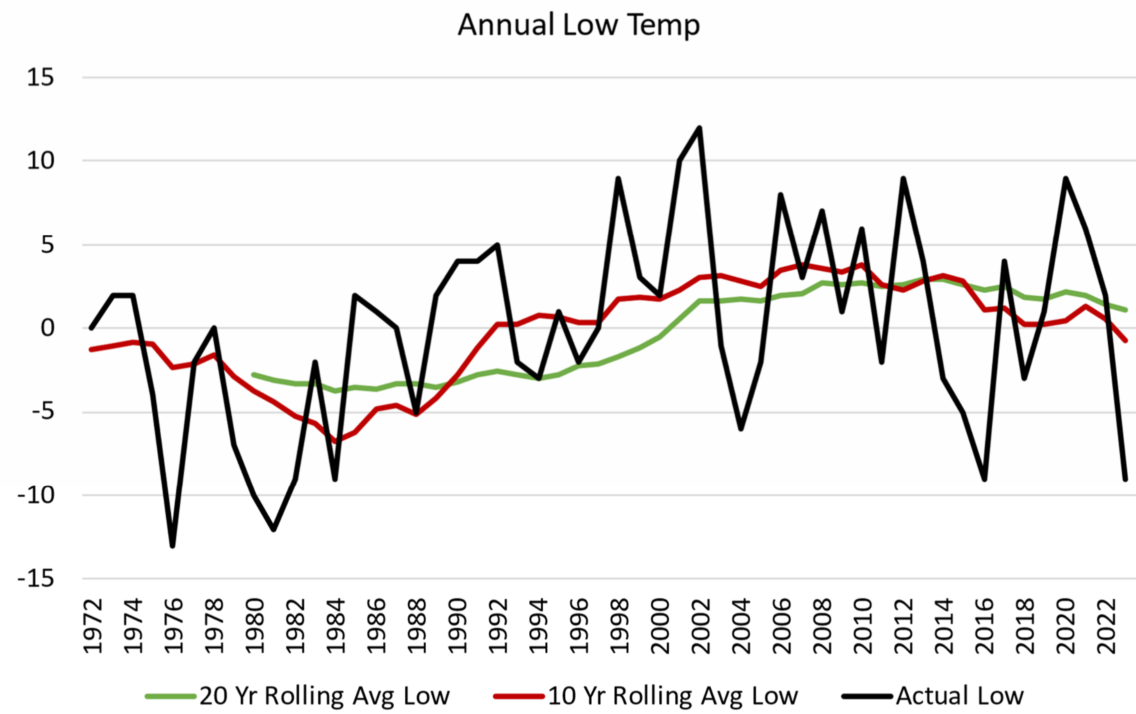


Figure 19: Historical Annual Low Temperatures (°F)



Comparison of 2024 Forecast to 2023 Forecast

Figure 20 provides a comparison of this year's summer peak (which is also the annual peak) forecast to last year's forecast. Generally speaking, there is very little difference between the gross forecasts, and the net forecasts are similar to the forecasts released in 2023.

Figure 20: Comparison of Current Forecast to Prior Forecast, Gross and Net, Summer 50-50

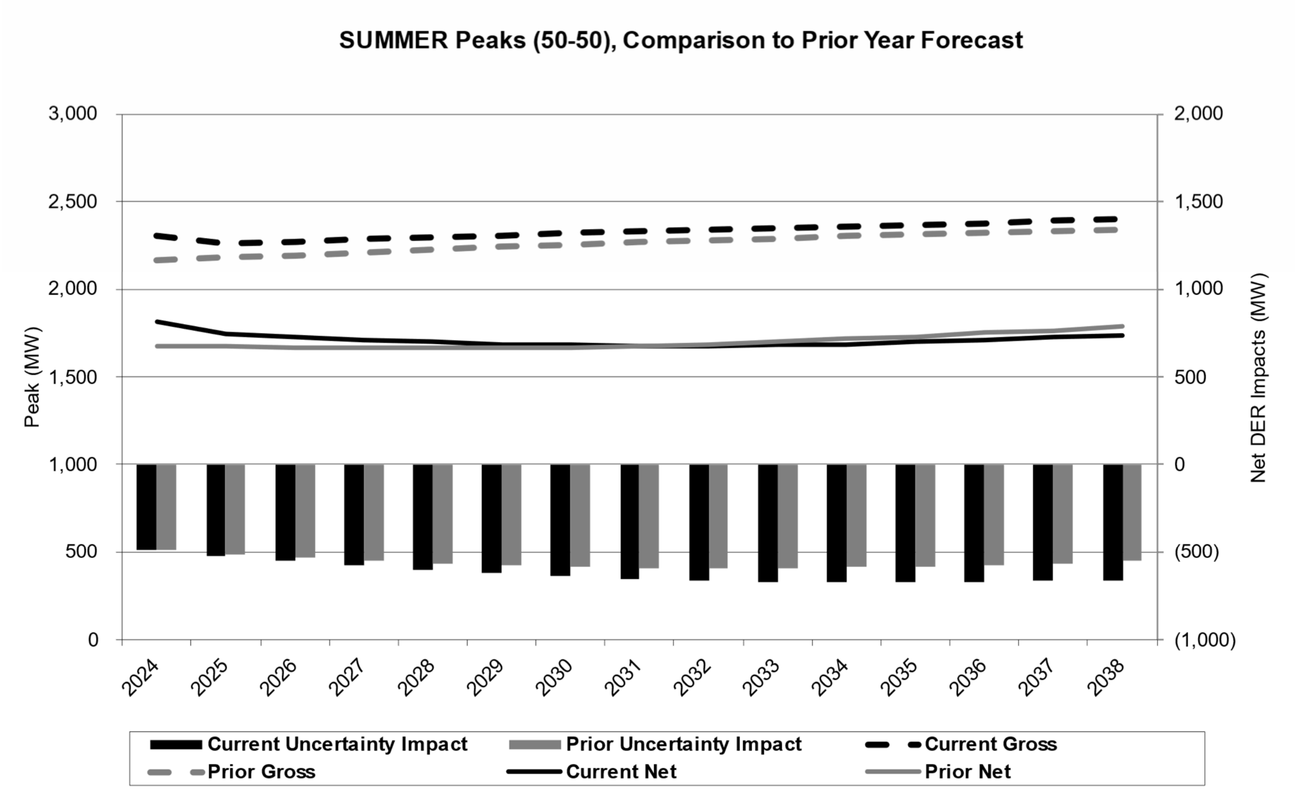
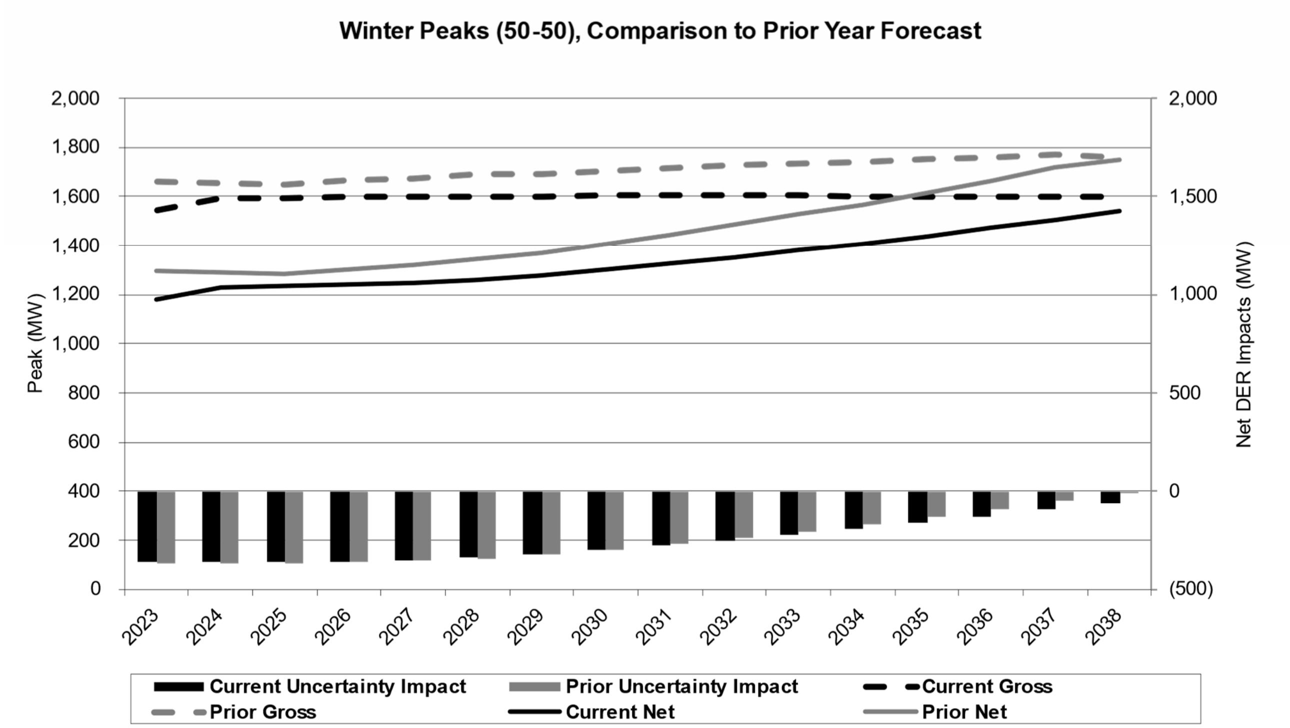


Figure 21 provides a comparison of this year's winter peak forecast to last year's forecast.

Figure 21: Comparison of Current Forecast to Prior Forecast, Gross and Net, Winter 50-50



Appendix A: Forecast Details